ADEQ Arizona Department of Environmental Quality

DRAFT TECHNICAL SUPPORT DOCUMENT

TECHNICAL REVIEW AND EVALUATION OF APPLICATION FOR AIR QUALITY PERMIT NO. 69734

Arizona Electric Power Cooperative, Inc. (AEPCO)

I. INTRODUCTION

This Class I renewal permit is issued to Arizona Electric Power Cooperative, Inc. (AEPCO), the Permittee, for continued operation of Apache Generating Station, located in Cochise, AZ.). The plant currently supplies wholesale electric power to six rural electric distribution systems serving portions of Arizona, California, and New Mexico. It also makes economy sales of electric power to other customers as market conditions permit. This is a renewal of Permit # 55412.

A. Company Information

1. Facility Name: Apache Generating Station
2. Facility Location: 3525 N. Hwy 191 South, Cochise, Cochise County, Arizona 85606
3. Mailing Address: P.O. Box 670, Benson, AZ 85602

B. Attainment Classification

This area is designated as attainment for all pollutants.

II. PROCESS DESCRIPTION

Apache Station currently supplies power through 3 Steam-electric generating units and 4 Gas turbines. Each unit's rated generation capacity and fuel usage type is listed in Table 1 below.

Table 1 – Generating Capacity

Unit	Rating (MW)
Gas Turbine 1 (GT1)*	10.51 MW (gas)
Gas Turbine 2 (GT2)	19.8 MW (gas), 19.8 MW (oil)
Gas Turbine 3 (GT3)	64.9 MW (gas)
Gas Turbine 4 (GT4)	44 MW (gas), 44 MW (oil)
Steam Unit 1 (ST1)*	75 MW (gas)
Steam Unit 2 (ST2)	194.7 MW (gas)**
Steam Unit 3 (ST3)	194.7 MW (coal/gas)

* GT1 and ST1 usually operate in combined cycle mode
**ST2 can operate on coal under emergency provision pursuant to the Regional Haze SIP

A. Units 2 and 3 (ST2 and ST3)

ST2 and ST3 are Apache Station's load-following generating units. They typically meet most of the power requirements of AEPCO's distribution cooperatives and other power contractors, as needed.

ST2 (when on coal during an emergency) and ST3 use natural gas ignitors during startup and certain other operating conditions. These conditions include boiler flame stabilization, equipment testing, and load stabilization. Firing of two or more fossil fuels simultaneously in ST2 and ST3 boilers is subject to a prorated NOx emissions limitation as outlined in 40 CFR 60.44(b).

AEPCO will occasionally use the ignitors to provide an additional source of fuel to the boiler (up to 20 percent heat input), which is an alternate operating scenario for ST2 and ST3 (i.e., co-firing natural gas and coal). AEPCO would record operation of the ignitors in this manner contemporaneously with the change in the operating logs for each affected unit.

B. Steam Unit 1 and Gas Turbine 1 (ST1/GT1)

The combined cycle unit, ST1/GT1 is the plant's primary backup unit. It is brought on line to meet increased load requirements during high demand periods or to supplement generation when ST2 or ST3, the larger generating units, are offline for repair or maintenance.

GT1 can operate independently in simple cycle mode without ST1 with the exhaust either directed through the ST1 windbox (for boiler drying and warming) or through a dedicated stack.

C. Gas Turbine 2 (GT2), Gas Turbine 2 (GT3) and Gas Turbine 4 (GT4)

Gas Turbines GT2 through GT4 are typically used during peak load demand. They also are available for backups when the larger generating units are offline for repair or maintenance.

D. Coal Handling System

The coal used by ST3 arrives at Apache Station by train. The railcars are unloaded into large hoppers, which feed through to conveyors to an aboveground storage. AEPCO typically maintains three separate piles of coal for use in the units based on the type of coal received. Coal is reclaimed from the separate piles with the aid of rotary plows. The rotary plows transfer coal through conveyors and deposit it into coal silos. From the coal silos, the coal is processed for use in the boiler.

E. ST3 Limestone Handling System

ST3 is equipped with SDASs that remove SO_2 from the boiler flue gases when the unit is burning coal. The limestone handling system provides the limestone required by the SDASs.

Pebbled limestone is dumped through the open dump hopper, and conveyed to the limestone storage bin, transferred to the inlet of the rotating ball mill. Water feed to the mill inlet is regulated in proportion to the limestone feed rate to produce a slurry. The slurry is then pumped to the wet cyclones for separation. The fine slurry overflow is stored in a storage tank and eventually fed to the reagent feed tank for use in the SO_2 removal process.

F. Ash Handling System

Coal combustion in ST3 produces an ash residue which either falls to the bottom of the furnace (bottom ash), or is carried out with the exhaust (or flue) gas leaving the boiler (fly ash). Apache Station’s ash handling system facilitates the storage or reuse of bottom ash and fly ash. Bottom ash is periodically sluiced from the bottom ash hoppers to the ash pit and then sluiced through a pipeline to the ash storage ponds, where it is impounded. Decanted ash sluice water is recycle back to the plant for re-use in ash sluicing.

Fly ash is captured in the economizer, electrostatic precipitator, and air heater hoppers. Fly ash is pulled from the hoppers to collecting tanks where it is mixed with sluice water. The fly ash slurry is then gravity fed to the ash pit and pumped to the ash storage ponds with the bottom ash as described above.

In addition to onsite storage, AEPCO also sells fly ash that meets product specifications for use in various products, including concrete. Fly ash to be sold is diverted from the fly ash collecting tanks into offsite third party storage silos.

G. Alternative Operating Scenarios

Table 2 – Primary and Alternate Operating Scenarios

Source	**Primary Operating Scenario**	**Alternate Operating Scenario**
GT1	Natural Gas	None
GT2	Natural Gas	No. 2 Fuel Oil
GT3	Natural Gas	None
GT4	Natural Gas	No. 2 Fuel Oil
ST2	Natural Gas	Coal, Emergency only
ST3	Coal	Natural Gas Co-firing Coal and Natural Gas

H. Control Devices

Table 3 – Control Devices

Source	**Control Device**	**Description**
GT4	Water injection, SCR and Catalytic Oxidation	Reduction of NOx and CO
ST1	Low-NOx burners	Reduction of NOx
ST2*	Low-NOx burners	Reduction of NOx
ST3	Low-NOx burners, SDAS, ESP and SNCR	Reduction of NOx, Control of SO_2, PM and NOx

*If Coal is used in ST2, SDAS and ESP controls will be utilized.

1. GT4

    a. Water injection is used in the combustion section followed by selective catalytic reduction (SCR) technology. The water injection in the combustion section is designed to lower NO_X at the turbine. The turbine outlet gas is then directed into the SCR for further NO_X control.

    b. Catalytic oxidation is used to control CO emissions. This control measure requires a dry catalyst bed located in the turbine exhaust path.

2. ST2 and ST3

    a. Electrostatic precipitators (ESPs) are used on ST2 and ST3 to control particulate matter (PM) emissions when coal is used as a primary fuel. The ESPs receive the exhaust gases coming from the boilers.

    b. A Sulfur Dioxide Absorption Systems (SDAS) is used to meet SO_2 emissions limitations when ST2 and ST3 use coal as a primary fuel. The SDAS or wet limestone scrubber on each coal-fired unit has two scrubber towers, also called absorber modules. These modules are where the reaction to remove SO_2 from the flue gas stream takes place. The system is designed for operation of one or both modules simultaneously.

    c. SNCR system injecting urea is used on ST3 for the control of NOx.

3. Coal Preparation Plant

    a. Dry fogging systems are used at the railcar unloading area, at the transfer point between Conveyor No. 1 and Conveyor No. 2, the transfer point between Conveyor No. 3 and Conveyors No. 4A and 4B, and at the three rotary plows, when they are in use to reclaim coal.

    b. Wet suppression and dry fogging systems are used at the track hopper feeders.

    c. A baghouse to capture particulate matter emissions are used at the enclosed shuttle Conveyors 5-2 and 5-3 as they transfer coal to the coal silos.

III. EMISSIONS

Table 4, 5 and 6 presents a summary of the maximum annual emissions from the facility.

Table 4 – Emissions Summary for Gas Turbines and Steam Units (tons per year)

Pollutant	**GT1 NG**	**GT2 NG / Oil**	**GT3 NG**	**GT4 NG / Oil**	**ST1 NG**	**ST2 NG / Coal**	**ST3 NG / Coal**
PM	230	343 / 13.74	752	13.1 / 3.63	792	849 / 827	15.8 / 248
PM_{10}	4.85	8.18 / 13.74	22.70	13.1 / 3.63	6.85	15.81 / 193	62.5 / 248
SO_2	2.5	4.22 / 57.81	11.70	0.97 / 0.24	2.16	4.99 / 6617	5 / 1238
NO_X	287	484 / 1007.39	1342	32.59 / 11.67	1010	1697 / 4136	1955 / 1898

Pollutant	GT1 NG	GT2 NG / Oil	GT3 NG	GT4 NG / Oil	ST1 NG	ST2 NG / Coal	ST3 NG / Coal
CO	60	102 / 3.78	282	39.64 / 2.84	302	333 / 209	333 / 204
VOC	1.54	2.6 / 0.047	7.22	6.4 / 0.34	19.84	45.75 / 25	45.80 / 24.5
Lead	ND	ND / 0.02	ND	ND	0.0018	0.0042 / 0.08	0.004 / 4.18
HAPs	0.72	1.22 / 1.5	3.52	1.41 / 1.9	6.8	15.7 / 273	15.7 / 208.5

NG = Natural Gas, Oil = Fuel Oil, Emission factors based on AP-42 and BART/SIP limits.

Table 5 – Emissions Summary for Coal Handling, Limestone Handling, and Cooling Towers Operations (tons per year)

Pollutant	Cooling Tower 1	Cooling Tower 2	Cooling Tower 3	Coal Handling	Limestone Handling
Particulate Matter	7.95	15.6	15.6	5,342	140
PM_{10}	3.98	7.8	7.8	2,673	31.5
HAPS	0.3	1.32	1.32		

Table 6 – Emissions Summary for Diesel Turbine Starter (tons per year)

Pollutant	GT1 Startup Engine
Particulate Matter	4.6
PM_{10}	4.6
SO_2	4.34
NOx	66.1
CO	14.2
VOC	5.24
HAPS	0.10

IV. APPLICABLE REGULATIONS

Table 7 displays the applicable requirements for each permitted piece of equipment along with a explanation of why the requirement is applicable.

Table 7: Verification of Applicable Regulations

Unit	Manufacture Date	Control Device	Rule	Discussion
Steam Unit 1	1963	None	A.A.C. R18-2-702.B A.A.C. R18-2-703.A A.A.C. R18-2-703.B A.A.C. R18-2-703.C.1 A.A.C. R18-2-703.K	Standards of Performance for Existing Fossil-fuel Fired Steam Generators and General Fuel-burning Equipment
			40 CFR 75	Continuous Emission Monitoring Requirements
			SPR 59195	Significant Permit Revision No. 59195, BART applicability.
Steam Units 2 and 3	1976	SNCR, ESP and SDAS for ST3. SDAS and ESP for ST2 only during emergency Coal usage.	40 CFR 60.Subpart D	Standards of Performance for Fossil-fuel Fired Steam Generators. PM and opacity limit in 40 CFR 60.42(a) does not apply to ST2 pursuant to 60.42(d) when combusting only natural gas.
			40 CFR 60 Subpart Da(a)	In lieu of Opacity requirements in 40 CFR 60.42(a) for ST3, Permittee has petitioned to comply with 40 CFR 60.42Da(a) pursuant to 40 CFR 60.42(c). PM CEMS are installed on ST3.
			A.A.C. R18-2-903.3.c.i	Standards of Performance for Fossil-fuel Fired Steam Generators
			40 CFR 72	Acid Rain Program
			40 CFR 73	Sulfur Dioxide Allowance Program
			40 CFR 75	Continuous Emission Monitoring Requirements
			SPR 59195	Significant Permit Revision No. 59195, BART applicability.

Unit	**Manufacture Date**	**Control Device**	**Rule**	**Discussion**
Steam Unit 3	1976		40 CFR 63 Subpart UUUUU	Coal- and oil-fired electric utility steam generating units. This rule is applicable to Steam Unit 3. Based on 40 CFR 63.10000(n), Steam Unit 2 will not be subject to 40 CFR 63 Subpart UUUUU after it is permanently converted to natural gas firing.
Steam Units 2	1976		40 CFR 63 Subpart DDDDD	NESHAP for major sources: industrial, commercial, and institutional boilers and process heaters. 40 CFR 63.7491 exempts an electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of part 63 firing at least 85 percent natural gas on an annual heat input basis. Thus, this Rule is not applicable to Steam Unit 2.
Gas Turbines 1, 2, 3 and GT1 Startup engine	GT1: 1963 GT2: 1972 GT3: 1975	None	A.A.C. R18-2-719	Standards of Performance for Existing Stationary Rotating Machinery
Gas Turbine 4	2002	Water Injection and SCR for NO_X Oxidation Catalyst for CO.	40 CFR Subpart GG 40 CFR 75	Standards of Performance for Stationary Gas Turbines Continuous Emission Monitoring Requirements
GT1 Startup engine and Emergency Generator	1990	None	40 CFR 63 Subpart ZZZZ A.A.C. R18-2-719	National Emissions Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines Standards of Performance for Existing Stationary Rotating Machinery

Unit	Manufacture Date	Control Device	Rule	Discussion
Water Heaters	N/A	None	A.A.C. R18-2-724	Standards of Performance for Fossil Fuel-Fired Commercial and Industrial Units The Boiler MACT 40 CFR 63 Subpart JJJJJJ does not apply to natural gas fired water heaters.
Coal Preparation Plant	1976-1977	Spray Bars, Dry Fogging And Baghouse On Silos	40 CFR 60 Subpart Y	Standards of Performance for Coal Preparation and Processing Plants
Limestone Handling Operations	1976 Weigh feeder and wet ball mill are 2011	Bag filter on limestone storage bin, Wetting bars.	A.A.C. R18-2-722	Standards of Performance for Existing Gravel or Crushed Stone Processing Plants.
Cooling Towers 1, 2 & 3	1: 1995 2: 2008 3: 2008	N/A	A.A.C. R18-2-730	Standards of Performance for Unclassified Sources. NESHAP 40 CFR 63 Subpart Q is not applicable because source does not use chromium based water treatment chemicals.
Fuel Oil Storage Tanks	N/A	N/A	A.A.C. R18-2-730	Standards of Performance for Unclassified Sources. A.A.C. R18-2-710 does not apply to the fuel oil storage tanks because these tanks do not handle petroleum liquids with a vapor pressure greater than 1.5 psia. Additionally, this rules exempts fuel oils No. 2 through No. 6.
Gasoline Storage Tanks	N/A	Submerged Filling Device	A.A.C. R18-2-710	Standards of Performance for Existing Storage Vessels for Petroleum Liquids 40 CFR 63 Subpart CCCCCC does not apply to the gasoline storage tanks because the facility is an area source for HAPs.
Fugitive dust sources	N/A	Water Trucks Dust Suppressants	A.A.C. R18-2 Article 6 A.A.C. R18-2-702	These standards are applicable to all fugitive dust sources at the facility.

Unit	Manufacture Date	Control Device	Rule	Discussion
Abrasive Blasting	N/A	Wet blasting; Dust collecting equipment; Other approved methods	A.A.C. R-18-2-702 A.A.C. R-18-2-726	These standards are applicable to any abrasive blasting operation.
Spray Painting	N/A	Enclosures	A.A.C. R18-2-702 A.A.C. R-18-2-727	This standard is applicable to any spray painting operation.
Demolition/renovation operations		N/A	A.A.C. R18-2-1101.A.8	This standard is applicable to any asbestos related demolition or renovation operations.
Roadway and Site Cleaning Machinery		None	A.A.C. R18-2-804.B	These are applicable to Roadway and Site Cleaning Machinery.

V. PREVIOUS PERMIT CONDITIONS

Permit No. 55412 was issued on July 23, 2013, for the continued operation of this facility. Table 8 below illustrates if a section in Permit No. 69734 was revised or deleted.

Table 8: Permit No. 69734

Section No.	Determination		Comments
	Revised	Delete	
Att. A.	X		General Provisions - Revised to represent most recent template language.
Att. B.I.D		X	Requirements of 40 CFR 63 Subpart UUUUU has been added in Section VI.
Att.B.II.A & B	X		Applicability & Fuel Limitation were revised to reflect ST2 conversion to natural gas fuel.
Att.B.II.B.5		X	Reporting of Representative Annual Actual Emissions Demonstration requirements has expired and thus removed.
Att.B.II.D	X		Particulate Matter (PM/PM10) and Opacity requirements were revised due to conversion to natural gas fuel and Permittee petitioned to comply with 40 CFR 60.42Da(a) pursuant to 40 CFR 60.42(c).
Att.B.II.D.4	X		CEMS requirement added.
Att.B.II.D.3.d		X	Compliance Assurance Monitoring (CAM) for PM has been removed because Continuous Emission Monitoring System (CEMS) is installed.
Att.B.II.D.4.a		X	Opacity testing requirement removed, see Att.B.II.D above.
Att.B.II.G & H		X	The Consent Order #A-17-09 has been terminated and the Mercury emission control is addressed by incorporating 40 CFR 63 Subpart UUUUU in Section VI of this renewal permit.
Att.B.III.B.2			Reporting of Representative Annual Actual Emissions Demonstration requirements has expired and thus removed.
Att.B.VI	X		Permit revised to include 40 CFR 63 Subpart UUUUU requirements.

VI. MONITORING REQUIREMENTS

The following monitoring approaches have been required in the permit:

A. Steam Units 2 and 3 (ST2 and ST3)

1. ST2 has continuous emission monitoring system (CEMS) for NOx, SO_2 and CO.

2. ST3 has continuous emission monitoring system (CEMS) for PM, NOx, SO_2 and CO.

3. AEPCO has an existing monitoring plan that apply to CEMS prepared under appendix B to 40 CFR Part 60 or 40 CFR Part 75 that meets site specific monitoring plan requirements under 40 CFR 63.10000(d)(1).

B. Gas Turbines 1, 2, and 3, Gas Turbine Startup Engine, and Emergency Diesel Generator.

1. Particulate Matter and Opacity:

   a. When fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

      (1) When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

      (2) When fuel oil is burned continuously for a time period > 168 hours, then for each 168 hour period one EPA Method 9 reading is required.

   b. When fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit, including the heating value and the ash content.

2. Sulfur Dioxide (SO_2)

   a. Natural gas

      The Permittee is required to maintain a copy of the FERC approved Tariff agreement on-site.

   b. Fuel oil:

      When fuel oil is burned, the Permittee is required to keep on record fuel supplier certification including the name of the oil supplier; the sulfur content and the heating value of the fuel from which the shipment came from; and the method used to determine the sulfur content of the oil.

C. Gas Turbine No. 4

1. Particulate Matter (PM/PM_{10})

   The Permittee must conduct a rolling twelve month calculation of the emissions of PM_{10} based initially on manufacturer's data, and after the initial performance tests upon the emission factors calculated for natural gas and fuel oil. The result of these tests and the recorded hours of operation of both fuels will be used to calculate the annual PM_{10} emission.

2. Sulfur Dioxide

a. While burning natural gas, the Permittee must maintain a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas.

b. While burning fuel oil, the Permittee must maintain records of fuel supplier certifications that including the name of the oil supplier, the sulfur content of the oil, the heating content of the oil, and the method used to determine the sulfur content of the oil.

3. Nitrogen Oxides

The Permittee is required to install and operate continuous emissions monitors to track nitrogen oxide emissions.

4. Carbon Monoxide

The Permittee is required to install and operate continuous emissions monitors to track carbon monoxide emissions.

D. Coal Preparation Plant

1. Opacity

a. Normal and Alternative Operation

The Permittee is required to make a weekly survey of the visible emissions from established points. The Permittee is required to create a record of the date on which the survey was taken, the name of the observer, and the results of the survey. If the visible emissions do not appear to exceed the standard, the Permittee would make a record of the date and time of the test, name of observer, and the results of the observation. If the visible emissions appear to exceed the standard on an instantaneous basis, the Permittee shall take a 6 minute observation of the plume.

b. While under Alternative Operation, the Permittee is also required to keep a record of the operating times of each piece of equipment. The Permittee is also required to conduct at least one opacity observation each time a piece of equipment is operated.

E. Limestone Handling Plant

1. The Permittee is required to maintain a record of daily production rates of limestone produced.

2. The Permittee is required to make a weekly survey of the visible emissions from the limestone handling system when it is in operation in accordance with Condition I.A. This weekly observation shall include observation of all exposed transfer

points, enclosed transfer points, and the bag filter. Permittee shall keep a record of the name of the observer, the date on which the observation was made, and the results of the observation

F. Fugitive Dust

1. The Permittee is required to keep record of the dates and types of dust control measures employed.

2. The Permittee is required to show compliance with the opacity standards by having a Method 9 certified observer perform monthly survey of visible emission from fugitive dust sources. The observer is required to conduct a 6-minute Method 9 observation if the results of the initial survey appear on an instantaneous basis to exceed the applicable standard.

3. The Permittee is required to keep records of the name of the observer, the time, date, and location of the observation and the results of all surveys and observations.

4. The Permittee is required to keep records of any corrective action taken to lower the opacity of any emission point and any excess emission reports.

G. Periodic Activities

1. The Permittee is required to record the date, duration and pollution control measures of any abrasive blasting project.

2. The Permittee is required to record the date, duration, quantity of paint used, any applicable MSDS, and pollution control measures of any spray painting project.

3. The Permittee is required to maintain records of all asbestos related demolition or renovation projects. The required records include the "NESHAP Notification for Renovation and Demolition Activities" form and all supporting documents.

VII. TESTING REQUIREMENTS

A. ST3

1. Particulate Matter

The Permittee shall perform an annual performance test to determine the particulate matter concentration from the stack associated with ST3 using EPA Reference Method 5, or 5B, or 17 or MATS Method 5 in accordance with 40 CFR 60.46.

B. ST2 and ST3

1. SO2

The Permittee shall perform an annual performance test to determine the sulfur dioxide concentration using EPA Reference Method 6 or 6C in accordance with 40 CFR 60.46.

2. NOx

The Permittee shall perform an annual performance test to determine the nitrogen oxides concentration using EPA Reference Method 7 or 7E in accordance with 40 CFR 60.46.

C. GAS TURBINE 1, 2, 3

1. NOx

The Permittee shall use EPA Reference Method 20 to conduct the performance test for nitrogen oxides emissions as specified in the Arizona Testing Manual for Air Pollutant Emissions.

2. CO

The Permittee shall use EPA Reference Method 10 to conduct the performance test for carbon monoxide emissions.

VIII. COMPLIANCE HISTORY

AEPCO has an open Consent Order (A-08-16). This renewal permit will have requirements for steam units ST2 and ST3 that addresses opacity compliance issue and sets PM standards. This is accomplished for ST2 by limiting it to combust natural gas such that the PM and opacity limit in 40 CFR 60.42(a) does not apply to ST2 pursuant to 60.42(d). For ST3, In lieu of Opacity requirements in 40 CFR 60.42(a), the Permittee has petitioned to comply with 40 CFR 60.42Da(a) pursuant to 40 CFR 60.42(c). PM CEMS are installed and certified on ST3.

IX. LIST OF ABBREVIATIONS

A.A.C. .... Arizona Administrative Code
ADEQ .... Arizona Department of Environmental Quality
AEPCO .... Arizona Electric Power Cooperative
BACT .... Best Available Control Technology
Btu .... British Thermal Unit
CAM .... Compliance Assurance Monitoring
CEMS .... Continuous Emission Monitoring systems
CERMS .... Continuous Emission Rate Monitoring System
CFR .... Code of Federal Regulations
CO .... Carbon Monoxide
CO_2 .... Carbon Dioxide
COMS .... Continuous Opacity Monitoring System
EPA .... Environmental Protection Agency
HAPs .... Hazardous Air Pollutants
HCL .... Hydrochloric Acid
NESHAP .... National Emission Standards for Hazardous Air Pollutants
NO_2 .... Nitrogen Oxide
NSR .... New Source Review
NSPS .... New Source Performance Standards
PM .... Particulate Matter
PM_{10} .... Particulate Matter Less Than 10 Microns
PTE .... Potential to Emit
SO_2 .... Sulfur Dioxide
tph .... Tons per Hour

VOC .... Volatile Organic Compound